


New Facilities Investment Test for Western Power's Mid-West Energy Project (Southern Section)

Prepared for the Economic Regulation Authority

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1. Introduction

In August 2011 Western Power submitted a major augmentation proposal for the Mid West Energy Project (Southern Section Stage 1) to the Economic Regulation Authority ("the Authority"). The proposal is to develop a 330kV double circuit line from Neerabup to the Karara mine site via Eneabba. The major augmentation proposal is submitted for assessment against the new facilities investment test (NFIT) contained in section 6.52 of the Electricity Networks Access Code 2004.

Marsden Jacob Associates (MJA) has been commissioned by the Authority to provide an economic assessment of the proposal against the requirements of the new facilities investment test.

1.1 The electricity networks access regime and the new facilities investment test

Part 8 of the Electricity Industry Act 2004 gives effect to the State's obligations under the Competition Principles Agreement to provide third party access to the services of electricity networks infrastructure in Western Australia. The principal instrument through which this obligation is satisfied is the Electricity Networks Access Code 2004 (Access Code), which has been established in accordance with the requirements of section 104 of the 2004 Act.

Before the cost of a major augmentation proposal can be added to the capital base of a covered network, and recovered via future reference tariffs, the new facilities investment required for that augmentation must satisfy the new facilities investment test of section 6.52 of the Access Code, as reproduced below:

6.52 New facilities investment satisfies the new facilities investment test if:

(a) the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs, having regard, without limitation, to:

(i) whether the new facility exhibits economies of scale or scope and the increments in which capacity can be added; and

(ii) whether the lowest sustainable cost of providing the covered services forecast to be sold over a reasonable period may require the installation of a new facility with capacity sufficient to meet the forecast sales;

and

(b) one or more of the following conditions is satisfied:

(i) either:

A the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment; or

B. if a modified test has been approved under section 6.53 and the new facilities investment is below the test application threshold – the modified test is satisfied;

or

(ii) the new facility provides a net benefit in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs; or

(iii) the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.

The assessment in this report is primarily concerned with the economic aspects of the NFIT, in particular 6.52(b). The Authority will also receive advice from a separately commissioned technical consultancy regarding the efficient minimisation of costs covered by section 6.52(a).

Section 6.53 provides for the possibility of a "modified test", although the service provider has not proposed a modified test in this instance.

Western Power has indicated that the combined incremental revenue and (non-overlapping) net benefits from the proposed augmentation are greater than the capital cost of the MWEP (Southern Section). In accordance with advice provided by the Authority in the *Issues Paper on the New Facilities Investment Test for a 66/11 kV Medical Centre Zone Substation Expansion and Voltage Conversion of the Distribution Network,* Appendix A, the combination of these elements would imply that the augmentation satisfies condition 6.52(b).

We examine the incremental revenue and the net benefits in sections 2 and 3 respectively. Note that throughout this document condition 6.52(b)(1)(A) is referred to as the 'incremental revenue test' and 6.52(b)(ii) is referred to as the 'net benefits test'. Western Power has not proposed to apply any value under 6.52(iii) for this application.

1.2 Choice of timeframe

Western Power's Contributions Policy (section 5.3(a)) refers to a maximum of 15 years when applying the incremental revenue test. However, as noted by Western Power in their submission, this timeframe is not appropriate for fully assessing the incremental revenue or net benefits of the MWEP (Southern Section) as both the costs and the benefits of the project are likely to accrue over a longer period.

Western Power note that Karara's resource could last more than 60 years (which is also the expected life of the MWEP steel towers) and Extension Hill's resource would be likely to last for 40 years. Western Power therefore selected a timeframe of 40 years for the incremental revenue test.

For the net benefits test, Western Power selected a timeframe of 20 years on the basis of advice from consultants ACIL Tasman that 20 years was the longest reasonable timeframe having regard to government policies (e.g. the renewable energy certificate scheme) and the economic characteristics of the SWIS (e.g. the age profile of generation). Western Power have indicated that beyond a 20 year timeframe, the risk of unanticipated government policy changes and how such changes might affect investment in the replacement of generation as it retires is 'too large to be useful'.

By contrast, Western Power considers a 40 year timeframe appropriate for the incremental revenue test based on comfort gained from its 'intensive analysis' of the demand and supply from Mid West iron ore mines. However, the continued operation of large scale iron ore mines in the region is dependent on a large number of variables, including global economic development, changes in technology and the level of competition, to name a few. MJA are of the opinion that there is a significant risk that circumstances could change significantly over time periods greater than 20 years. Therefore, at the conclusion of this report we provide an analysis of the net benefits based both on Western Power's original timeframe and a truncated timeframe of 20 years.

2. Incremental Revenue

2.1 Incremental revenue test

The incremental revenue test compares the anticipated incremental revenue for a new facility against the new facilities investment. *"Anticipated incremental revenue"* for a new facility means:

> *(a) the present value (calculated at the rate of return over a reasonable period) of the increased income from charges (excluding any contributions) reasonably anticipated to arise from the increased sale of covered services on the network to one or more users (where "increased sale of covered services" means sale of covered services which would not have occurred had the new facility not been commissioned),*
>
> *minus*
>
> *(b) the present value (calculated at the rate of return over the same period) of the best reasonable forecast of the increase in non-capital costs directly attributable to the increased sale of the covered services(being the covered services referred to in the expression "increased sale of covered services" in paragraph (a) of this definition).*

Western Power has estimated the incremental revenue from both iron ore mines and wind turbine operators.

2.2 Iron ore revenue estimates

Incremental revenue is calculated as the price multiplied by the quantity demanded by new customers or increased demand from existing customers.

2.2.1 Price

The 'nodal' price estimate is based on two components – one for use of the existing system and a price for use of new assets. The price for the existing system corresponds to the 2010/11 Price List Information for the Malaga substation. Although the actual connection to the existing 330kV network will be at the Neerabup substation, a published price is not available for that substation and Western Power has deemed the Malaga substation to be the best representative connection point.

The second element (the price for new assets) has been calculated using building block costs associated with the new assets (depreciation, return on assets and operating costs), except that the capital costs per kilometre of line are based on Western Power's Physical Assets Valuation report produced for regulatory purposes in 2004 and included in the AA1 documentation submitted to the Authority on 19 May 2006. Western Power indicates that the calculation conforms with the nodal price calculation described in the Price List Information detailed in the Access Arrangement Price List Information, page A-2 under the heading *"A connection that is unlikely to be shared by other users"*. We note that the information provided in this Appendix of the Price List Information is at a high level only and does not specifically mention the valuation of assets using the 2004 valuation report.

It is unclear why Western Power have used the valuations from 2004 rather than the modern efficient asset value, which would be the full capital cost approved under the NFIT. Applying the full capital cost would almost double the price to Karara and Extension Hill compared with the current method.

2.2.2 Demand

For the purposes of the NFIT, Western Power has assumed that the new demand for the MWEP (Southern Section) will drive primarily from the Karara and Extension Hill mines. Western Power has developed estimates of iron ore production in the Mid West region based on a probabilistic model driven by assumptions including the long term price of iron ore and the cost of production, which have been developed through consultancies, research and consultation with government departments. The modelling necessarily contains some simplifications and extrapolation, but is considered a reasonable approach in lieu of firm commitments from iron ore producers.

The incremental revenue is partially protected from demand fluctuations as the price for new assets is based on the cost of those assets divided by demand. Therefore if demand is less than forecast, the price will be higher. In addition, Western Power has indicated that it will seek 15 year contracts for Contracted Maximum Demand (CMD), which would further reduce demand risks.

2.2.3 Actual prices charged to Karara and Extension Hill

Western Power has not specified that the prices calculated in the incremental revenue model will be the actual price charged to Karara or Extension Hill. The intention of the incremental revenue test is to understand whether revenue from new customers will outweigh the cost and therefore will not require higher reference tariffs for other customers.[1] Estimates of anticipated incremental revenue should therefore be based on the most realistic forecasts of the price that would be charged to new customers.

In a letter to Rob Pullella (Authority) on 27 September 2011, Western Power acknowledged that a bank security requirement of $95 million would be required from Western Power and was '*equal to the anticipated incremental revenue derived from the connection of KML's Stage 1 operation (a CMD of 120MW)*'. While not explicitly confirming that the values in the incremental revenue model represent estimates of the price that will actually be charged, we note that the $95 million does appear in Western Power's incremental revenue model as the median value of revenue that would be received from Karara Stage 1.

Notwithstanding the above, the Authority should satisfy itself that the prices used in the incremental revenue model reflect Western Power's best estimate of the prices that will actually be charged to Karara and Extension Hill.

2.2.4 Consistency of demand estimates between the Regulatory Test and NFIT

The demand estimates provided in the incremental revenue model provided by Western Power (which form the basis of the estimates in the NFIT submission) relate primarily to load from Karara

[1] As evidenced by 6.52(b)(ii), which implies that, failing the Incremental Revenue test, a net benefit test is required to demonstrate that the *'new facility provides a net benefit in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs'*.

Stage 1 (120 MW) and 2 (60 MW), and Extension Hill (110 MW). The combined demand from these mines is 290 MW.

The level of demand used in the incremental revenue model does not align with the demand estimates provided in the Regulatory Test. The Regulatory Test included a Central estimate of 297 MW and a High estimate of 652 MW by 2020.

In response to questions raised by MJA and the Authority, Western Power noted that there were a number of significant differences between the demand provided in the Regulatory Test and the NFIT submission. For example, Western Power states that *'the probabilistic modelling underpinning the NFIT submission indicated that Stages 3 and 4 are unlikely to materialise'*.[2]

Western Power also notes that:

> *The Port of Oakajee and Oakajee Industrial Estate loads were excluded from the NFIT incremental revenue and net benefit calculations since the NFIT submission is focused on justifying the MWEP (Southern Section) without requiring the eventual construction of the MWEP (Northern Section).*
>
> *There are also other block loads included in the Regulatory Test High Load Peak Forecast that may or may not require MWEP (Northern Section):*
>
> - *the various Geraldton Port loads*
> - *the Extension Hill slurry pipeline.*
>
> *These loads were also excluded from the NFIT submission calculations since these are north of the termination point for the MWEP (Southern Section). Excluding these loads avoids potentially double counting the loads under a future NFIT submission for the MWEP (Northern Section).*
>
> *In addition to differences in block loads, the incremental revenue calculations underpinning the NFIT submission exclude natural load growth. This exclusion was considered appropriate on the basis that it would be accommodated via alternatives to the MWEP (Southern Section).*

If demand estimates were higher, as reported for the Regulatory Test, the additional revenue generated by this demand would increase the benefits under the Incremental Revenue test. By contrast, the lower demand estimates of the NFIT would cast doubt on the results of the original Regulatory Test.

In MJA's response to Western Power's Regulatory Test Submission for this project, we noted *"Assuming that the costs provided in their submission are correct, Western Power's preferred option (Option 4) is the most economically attractive option provided the likelihood of requiring more than 510 MW by 2016 is greater than 18%."*

Based on the information provided in the Western Power's incremental revenue model, the total CMD for Karara and Extension Hill would be greater than 290 MW in only 2% of cases. If, as noted in the NFIT responses, natural load growth will be "accommodated via alternatives to the MWEP", then even with the construction of the MWEP (Northern Section) and an assumption that all small

2 Western Power letter to Rob Pullella (ERA) 13 September 2011.

block loads (113 MW) would occur with a 100% probability, the likelihood that total demand for the MWEP (Southern Section) would be greater than 403 MW would be only 2%.

We understand that there may be other, technical reasons that the selected option (Option 4) was preferred, however the lower demand estimates utilised in the NFIT suggest that the selected option may not have been preferred from an economic perspective.

Ideally, the information provided by Western Power for the Regulatory Test should be recast with a demand profile consistent with the NFIT application.

2.3 Revenue from wind turbine operators

Western Power has allowed for revenue of $19 million from wind turbine operators. We note that this charge should also appear as a cost to wind turbine generators, which in turn will reduce the market benefits of generation.

ACIL Tasman's report on net benefits (see section 3.1) does not appear to include payments by wind turbine operators to Western Power, although it is possible these may be included under the variable or fixed operating costs.

The Authority should confirm whether ACIL Tasman's market benefits include payments from wind turbine operators.

3. Net Benefits

The net benefits presented in Western Power's NFIT application include market based benefits to customers and generators ($236 m), system loss reductions ($9 m) and capital expenditure deferrals ($26 m).

3.1 Market benefits

Western Power commissioned ACIL Tasman to estimate benefits that are likely to be derived from:

- reductions in the total cost of energy to consumers (i.e. energy cost savings)
- increase in generation revenue.

Since the completion of the ACIL Tasman report in June 2010 the Commonwealth Government has replaced its enhanced renewable energy target (ERET) with a small-scale technologies scheme (SRES) which include domestic photovoltaic and solar hot water and a large-scale renewable energy target (LRET). ACIL Tasman provided advice on April 2011 that while the slightly lower outlook for large-scale generation certificates (LGCs, formerly known as RECs) will marginally reduce net market benefits, changes to capital cost estimates are likely to reduce the difference in new entrant development costs and enhance the net market benefits of the MWEP (Southern Section). On balance, ACIL Tasman advised that the estimates of net market benefits as shown in the original report were considered robust and suitable for use in the regulatory test.

In order to develop estimates of energy cost savings to consumers and increases in generation revenue, economic models of the entire market were employed. ACIL Tasman used two in-house market models: *RECMark* and *WA PowerMark*. *RECMark* examines the profitability of renewable projects and therefore the timing and magnitude of entry into the market, based on assumptions including:

- Commonwealth renewable energy targets;
- currently committed and proposed renewable projects (including efficiency, capital costs or operating costs);
- future possible renewable projects;
- black energy price and other income for all electricity generating regions;
- REC shortfall penalty; and
- limited banking/borrowing of RECs.

The *WA PowerMark* model uses the results from *RECMark* as an input.

ACIL Tasman's *WA PowerMark* model assumes that, over the longer term, STEM prices will provide an indicator of wholesale electricity prices. The modelling adds open cycle gas turbine (OCGT) peaking plant to provide the capacity required by the Independent Market Operator (IMO) until the STEM price plus capacity payment reaches a level which justifies the addition of the lowest cost base load new entrant.

The modelling and most of the assumptions utilised by ACIL Tasman are self-referenced, presumably for brevity and to maintain commercial confidentiality. However, based on a review of the document as presented, MJA has no reason to doubt the veracity of the analysis or the conclusions. MJA also considers the methodology to be appropriate for the purposes of the Net Benefits test.

3.1.1 Modelling results

The modelling demonstrates that the primary benefit of the MWEP (Southern Section) is the ability to connect wind generation. The low running cost of wind generation reduces prices to customers and the availability of renewable energy certificates increases revenue to generators. The costs and benefits to generators and customers of Western Power's nominated option (ACIL Tasman's Scenario 5) are shown in Table 1.

Table 1: Costs and benefits to generators and customers

Description	With MWEP	Without MWEP	Change due to MWEP
Generation Costs			
Fixed costs for new plant (capital and fixed O&M)	$2,459	$2,231	$227
Variable costs for all plant (SRMC incl carbon)	$14,453	$14,724	-$271
Cost of generation ($ million)	**$16,912**	**$16,956**	**-$44**
Generation revenue			
STEM Revenue	$13,922	$14,071	-$149
Capacity revenue	$7,253	$7,253	$0
LGC (formerly REC) revenue	$666	$474	$192
Steam Revenue	$2,300	$2,299	$1
Total Generation Revenue	**$24,141**	**$24,097**	**$44**
Net Benefit to generators			**$87**
Cost to consumers			
Cost of STEM energy	$13,922	$14,071	-$149
Cost of capacity credits	$7,253	$7,253	$0
Total cost of Wholesale electricity	**$21,175**	**$21,325**	**-$149**
Net benefit to electricity consumers			**$149**
Total net benefit for generators and consumers			**$236**

The underlying changes to costs and revenue are shown in blue above and comprise additional fixed cost ($227m) for CCGTs and wind power, the lower running costs of wind power generation (-$271m) and higher renewable energy certificate revenue ($192m). The remaining changes, shown in red, relate to STEM revenue (which is a transfer between customers and generators), capacity credits (which remain the same with and without the MWEP) and steam revenue (which is a very small component).

In a competitive market, it would be expected that all benefits would ultimately be passed through to customers in the long run. However, for the purposes of the NFIT it is irrelevant whether the benefits accrue to generators or customers and therefore the distinction between beneficiaries is not critical to the analysis.

The results imply that the cost of wind generation minus the revenue from LGCs is substantially less than the cost of fossil fuel based energy generation.

The results shown in Table 1 assume that ACIL Tasman's Scenario 5 is appropriate. Scenario 5 is similar to ACIL Tasman's 'Base case' except that it presumes a 'high' rather than 'medium' growth rate. Western Power has used the higher load growth forecast based on its assessment of load requirements in the Mid West region. However, the high growth scenario used in the ACIL Tasman modelling refers to high growth across all regions, including North (north of Eneabba), Central (including Kalgoorlie) and South. Without an explicit rationale for expecting high growth across all regions, MJA considers it more appropriate to use ACIL Tasman's medium forecast.

The difference between ACIL Tasman's high growth scenario (Scenario 5) and the 'Base Case' is only $11 million in present value terms.

3.2 Large-scale Generation Certificates

In determining the market benefits, ACIL Tasman has provided an estimate of the revenue from LGCs based on the forecast price and the modelled quantity with and without the MWEP (Southern Section). The difference between the two cases represents the additional availability of wind farm generation with the MWEP augmentation.

ACIL Tasman assumes that the cost of LGCs will increase over time. This assumption appears at odds with advice provided by MMA to the Department of Climate Change. In answer to questions raised by MJA and the Authority, ACIL Tasman explained that the key differences between their estimate and the estimate provided by MMA are:

- that MMAs analysis reflected the contract prices required to ensure viability of renewable projects, while ACIL Tasman provided REC market price projections;
- the two firms held a difference of opinion about the likely rate of development of renewable energy projects. This determines the extent to which market prices hit the penalty ceiling;
- ACIL Tasman's projections are in nominal terms, whereas MMA's are in real terms.

The reconciliation provided by ACIL Tasman appears reasonable, however some difference of opinion appears to remain between MMA and ACIL Tasman. The following chart was provided by ACIL Tasman to demonstrate the relative position of each organisation.

Figure 4: MMA and ACIL Tasman RECs market price projections

Notes: Both ACIL Tasman and MMA projections have been adjusted for inflation to derive comparable projections in June 2011 dollars.

Source: McLennan Magasanik Associates (9 October 2007), *Review of REC Markets*, p. 28, Table 4-2; http://www.orer.gov.au/publications/pubs/modelling-2007.pdf

ACIL Tasman (June 2010), *Net market benefits of Mid West transmission link, Assessment of the market benefits of the southern stage of the proposed Mid West transmission line to Eneabba*; p. 29, Table 12.

The difference between the two estimates would have a substantial impact on the net benefit of the MWEP (Southern Section). Preliminary estimates by MJA suggest that the difference could be over $70 million in present value terms. However, as both estimates appear plausible and a comprehensive investigation of the difference between the estimates is beyond the scope of this study, we recommend that the estimates provided by Western Power's consultants be considered defensible for the purposes of the NFIT.

3.3 Other benefits

In addition to market based benefits, Western Power has indicated that other benefits of the MWEP (Southern Section) include system loss reductions and capital expenditure deferrals.

The system loss reduction benefit reflects the fact that the majority of underlying load will flow through the 330 kV MWEP line rather than the existing 132 kV network. Western Power calculates the present value benefit of these loss reductions as $8.9 million.

The second identified benefit relates to deferral of the reinforcements that would need to be undertaken to ensure maintenance of supply in the absence of the MWEP augmentation. Western

Power compared two scenarios, one in which reinforcement of the 132kV line continued (assuming Karara does not connect) and the alternative network solution if the 330kV MWEP (Southern Section) is in place. Western Power estimate that the deferral benefit for the project is $26 million under the high load forecast.

Each of these benefits outlined above appear reasonable. Combined, these benefits represent only 7% of the total benefits and are therefore unlikely to significantly affect the results of the NFIT.

4. Conclusions

4.1 Costs and benefits

A summary of the costs and benefits described by Western Power in the NFIT application is shown in Table 2.

Table 2: Western Power NFIT costs and benefits summarised

BENEFITS			
Incremental Revenue (median values)			
Karara Stage 1 (including $15m 'interim' revenue)	$119 m		
Karara Stage 2	$12 m		
Extension Hill	$72 m		
Less operating costs	-$17 m		
Net incremental mining revenue		$187 m	
Incremental wind turbine generation revenue		$19 m	
Total Incremental Revenue			**$206 m**
Net Benefits			
Market-based benefit – higher fixed costs (incl capital)	-$227 m		
Market-based benefit – lower marginal costs	$271 m		
Renewable energy certificates (LGCs)	$192 m		
Total market based benefits		$236 m	
System loss reduction		$9 m	
Capital expenditure deferral		$26 m	
Total 'Net Benefits'			**$271 m**
TOTAL NFIT BENEFITS			**$476 m**
COSTS			
Pinjar to Eneabba Substation line and associated works		$256 m	
Three Springs Terminal		$41 m	
Eneabba Substation to Eneabba Terminal line works		$12 m	
Eneabba Terminal to Three Springs line works		$75 m	
TOTAL NFIT COSTS			**$383 m**

In general, the analysis provided by Western Power is methodologically sound, however a number of specific issues were identified by MJA. These key issues are summarised in turn below.

4.2 Key issues

Actual prices to be charged to Karara and Extension Hill

There is a lack of clarity regarding whether the prices used in the incremental revenue model reflect the actual prices that will be charged to Karara and Extension Hill.

Use of historic asset valuations for calculating 'nodal' prices

In calculating the prices related to 'new assets', it is unclear why Western Power has used asset valuations based on 2004 unit costs rather than efficient asset costs, in particular those that would be approved under the NFIT.

Analysis over 20 year timeframe

The analysis provided by Western Power uses a 20 year time frame to calculate net benefits and a 40 year timeframe to calculate incremental revenue. Western Power has indicated that the shorter timeframe used in the former is due to the risk associated with government policy decisions, while their estimates of iron ore production in the region supports the latter. However, MJA is of the opinion that the risks associated with iron ore demand beyond 20 years are significant.

To sensitivity test the results, MJA utilised Western Power's incremental revenue model and found that reducing the timeframe to 20 years (i.e. 2012-2032) results in a median present value of $160 million rather than the $187 million reported over the longer time period.

Net benefits based on medium growth

The net benefits in the NFIT submission are based on a high growth rate across all regions (North, Central and South). Without an explicit rationale for the use of a high growth rate, MJA consider it appropriate to utilise the 'medium' growth rate (the 'Base Case') developed in the market benefits report. The 'Base Case' has benefits $11 million lower than the high growth case in present value terms.

Wind turbine generation revenue

Western Power has allowed for revenue of $19 million from wind turbine operators. This should effectively appear as a cost to wind turbine generators, which in turn will reduce the market benefits of generation. The Authority should confirm whether ACIL Tasman's market benefits include payments from wind turbine operators.

4.3 Summary

In summary, MJA has identified a number of issues that may require explanation or revision by Western Power. These include the potential use of a 20 year timeframe (which would result in a reduction to incremental revenue of $27 million), the use of medium rather than high system-wide growth estimates for calculation of the net benefits (a reduction in net benefits of $11 million), the inclusion of payments to Western Power for wind turbine generation (a reduction to net benefits of $19 million).

If all of the above adjustments were required, the total impact would be a reduction of $57 million in benefits. Even with this adjustment, the total benefits ($419 million) would still outweigh the cost of the new facility ($383 million). Therefore the resolution of these issues is unlikely to result in the project failing the NFIT.

Importantly, three matters still require resolution:

- the demand estimates provided for the NFIT appear to cast doubt on the previous results of the Regulatory Test. The Authority should consider the implications of the revised information;
- the Authority should confirm whether the price utilised in the incremental revenue model is expected to reflect the actual price charged to Karara and Extension Hill. If not, the anticipated incremental revenue should be recast based on expected prices; and
- the Authority should clarify why the full capital cost of the MWEP (Southern Section) has not been used to calculate 'nodal' prices. Applying the full capital cost would significantly increase the price charged to Karara and Extension Hill.